Table 2-3 Calpuff Control File

Parameter/Option	Value
Size parameters - dry particle deposition	Default
RCUTR	30.
RGR	10.
REACTR	8.
NINT	9
IVEG	2
Wet deposition parameters	Default
Ozone data input option	1
Background ammonia conc. (ppb)	2.
SYTDEP	550.
MHFTSZ	0
JSUP	5
XSAMLEN	0.5
MXNEW	99
MXSAM	99
Maximum mixing height (m)	4000.
Minimum mixing height (m)	50.
NSPLIT	3
IRESPLIT	Hour 17-22 = 1
ZISPLIT (m)	100.
ROLOMAX	0.25

Table 2-4 Non-IWAQM Settings Used by EPA in Calpuff Control File

Parameter	IWAQM	EPA
MSPLIT	0	1
MDISP	3	2
BCKO3	80 ppb	30 ppb
BCKNH3	10 ppb	2 ppb
XSAMLEN	1.0	0.5
XMAXZI	3000 m	4000 m
MPDF	0	1

MSPLIT - The option for puff splitting is employed when modeling source-receptor distances of 200 km or more, because of the tendency for Calpuff to otherwise overpredict at these distances. Deployment of this option also provided better agreement with observations.

MDISP - Use of dispersion coefficient option 2 provided better agreement with observations. Selection of this option reduced predicted concentrations by 25 percent or more at some receptors.

BCKO3 -EPA used files of measured hourly ozone concentrations to establish background values, however, the BCKO3 value is substituted by Calpuff when hourly data are missing. Based on local monitoring data the IWAQM value of 80 ppb appears to be too high for North Dakota conditions, and therefore was reset to 30 ppb.

BCKNH3 - The value of 2 ppb reflects the annual average of local, unbiased monitoring data.

XSAMLEN - This value was set lower than the IWAQM recommendations to improve model resolution by increasing the number of puffs and decreasing mass per puff. The only negative consequence for revising this option would be extra computer processing time due to more puffs on the grid.

XMAXZI - Value was increased to 4000 m for consistency with ZIMAX/ZIMAXW setting in Calmet.

MPDF- This option should be deployed when dispersion option 2 is selected.

3. Emission Inventory for Class I Increment Analysis

In general, the source emission inventory for any increment analysis consists of all increment-affecting sources[6]. Specifically, this would include actual emissions from:

(1) any major stationary sources for which construction began after the major source baseline date (which, for SO_2 is January 6, 1975);

(2) any existing major stationary sources having undergone construction (*i.e.*, a physical change or change in the method of operation) after the major source baseline date;

(3) any existing stationary sources having undergone a physical change or change in the method of operation, or having increased hours of operation or capacity utilization, after the minor source baseline date;

(4) any new stationary sources which were constructed after the minor source baseline date; and

(5) any changes in emissions from area and mobile sources since the minor source baseline date.

The "minor source baseline date" is defined as the earliest date after the "trigger date" (which for SO_2 is August 7, 1977) that a major stationary source or major modification submits a complete PSD permit application. The minor source baseline date is set for the baseline area for the increment pollutant which the source would emit in significant amounts. (See 40 CFR 51.166(b)(14)(ii) and (iii), 40 CFR 52.21(b)(14)(ii) and (iii)). The applicable minor source baseline date in any increment analysis is the minor source baseline date *for the area that is being modeled for impacts.* The SO_2 minor source baseline date was triggered for the North Dakota "Rest of State" (Air Quality Control Region 172) SO_2 attainment area on December 17, 1977. So, for assessing the impacts in Theodore Roosevelt National Park and Lostwood

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[6] New Source Review Workshop Manual, Part I, Chapter C, Section IV.C.2, p. C.35, Draft October 1990, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, http://www.epa.gov/ttnnsr01/gen/wkshpman.pdf.

Wilderness Area (both included in Air Quality Control Region 172), the applicable minor source baseline date is December 17, 1977. The SO_2 minor source baseline date for the Medicine Lakes Wilderness Area and the Fort Peck Indian Reservation in Montana was triggered on March 26, 1979, over a year later. Therefore, two emission inventories were compiled for this analysis: the inventory for the North Dakota Class I areas includes all increment affecting sources based on a minor source baseline date of December 17, 1977 and the inventory for the Montana Class I areas includes all increment affecting sources based on a minor source baseline date of March 26, 1979. Note that, the NDDH did not develop a separate inventory for the Montana Class I areas in their 1999 draft modeling analysis. Their results are based only on North Dakota's December 17, 1977 minor source baseline date.

The two inventories include increment consuming, as well as increment expanding sources and consist of all major PSD sources located within 250 km of each Class I area as well as minor sources located within 50 km of each North Dakota Class I area[7]. The major source inventory includes increment consuming emissions from eight coal-burning power plants (one of which is located in Montana), two gas processing plants and a coal gasification plant (see Figure 2-1) as well as increment expanding emissions from five major sources that all shut down after the applicable minor source baseline dates.

Modeled emissions (*i.e.*, increment consuming/expanding emissions) are determined by subtracting base year emissions from current year emissions, for each existing source. For sources constructed after the applicable baseline date, modeled emissions are the source's current year emissions minus zero emissions in the base year (*i.e.*, all emissions are modeled as increment consuming). For sources shut down after the applicable baseline date, modeled emissions are zero emissions in the current year minus the source's base year emissions (*i.e.*, all emissions are modeled as increment expanding).

3.1 Current Year Inventory

In general, emissions for the current year inventory are based on actual emissions reflected by normal source operation for a period of two years. The two-year study period should generally be the most recent two years, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the date of

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[7] The minor source inventory consists primarily of emissions from oil and gas facilities located in North Dakota. At the time of this report, emission and stack data were not available for the oil and gas production facilities found in the vicinity of Medicine Lakes Wilderness Area and Fort Peck Indian Reservation in Montana. Therefore, these minor source contributions were not accounted for in modeling PSD increment consumption in Montana Class I areas. Also, NDDH is updating the base year and current year oil and gas emission inventory for North Dakota. The current EPA modeling does not include emissions, either increment expanding or increment consuming, from these sources. EPA intends to incorporate NDDH's revised oil and gas emissions inventory, if available, into the final modeling analysis. We note, however, that given the relatively small magnitude of SO_2 emissions from oil and gas sources, the effect of including these sources in the final modeling analysis is likely to be small.

concern. (See 45 FR 52718, August 7, 1980). For the most part, the current year inventory for this analysis is based on continuous emission monitor system (CEMS) data from 1999 and 2000 as reported to the EPA Acid Rain Database.

Following is a brief description of each major source that was constructed after the major source baseline date for SO_2 (see Section 3.2 for similar descriptions on the baseline sources, all constructed before the major source baseline date). Information is based on data from EPA's Acid Rain Database (see http://www.epa.gov/airmarkets/picturethis/index.htm):

Basin Electric Power Cooperative - Antelope Valley Station
Unit 1 - 435 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) flue gas desulfurization (FGD)
Unit 2 - 435 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD

Otter Tail - Coyote Station
Unit 1 - 450 MW, cyclone-fired lignite boiler, SO_2 control - (dry lime) FGD

Great River Energy - Coal Creek Station
Unit 1 - 506 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD
Unit 2 - 506 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD

PPL Corp. - Colstrip (Montana)
Unit 3 - 778 MW, tangentially-fired boiler, SO_2 control - (wet lime) FGD
Unit 4 - 778 MW, tangentially-fired boiler, SO_2 control - (wet lime) FGD

Great River Energy - Stanton Station
Unit 10 - 60 MW, tangentially-fired boiler, SO_2 control - (dry lime) FGD

Hourly CEMS data for 1999 and 2000 for each of the eight power plants in the major source inventory (including 4 baseline sources) were obtained from EPA's Acid Rain Program. For each source, daily average emissions (24 hour averages) were calculated. Since it is highly unlikely that, simultaneously, all sources would operate at their peak actual emissions during the same 24-hour averaging time, we chose to model the 90th percentile actual emissions for each unit. In reviewing the 1999 and 2000 CEMS data, EPA found that the 90th percentile cumulative emission rate (*i.e.*, the sum of all of the 90th percentile emission rates at each facility) did actually occur several times. Therefore, given that, and the fact that these power plants are primarily used as base-load facilities, this seems like the most representative method for determining current year emissions, and provides a reasonable estimate of worst case conditions that may recur in the future.

The 90th percentile emission rate for each source was determined by ranking (from highest to lowest) the source's 24-hour average emission rates over 2 years - for a total of 730 emission rates (where the data record is 100% complete) - and selecting the 73rd highest 24-hour average emission rate from the list. This single emission rate was then modeled for every 24-hour period over the 5 years of meteorology data used in the model.

There are a couple exceptions to the above method for determining current year emissions. Current year emissions for Great River Energy's Coal Creek Station are based on year 2000 CEMS data only. Both units at the Coal Creek Station reduced their SO_2 emissions by approximately 20,000 tons (combined) in 2000. Prior to 2000, roughly 40% of the units' emissions were bypassing the wet lime scrubbers used to control SO_2 emission from the stacks. In 2000, the facility greatly reduced this bypass, resulting in approximately 20,000 tons of SO_2 emissions reduction over the year. Both units at Coal Creek Station are subject to the Acid Rain Program's Phase II requirements (which applied, starting in 2000, to all existing utility units serving generators with an output capacity of greater than 25 megawatts). Therefore, the source was able to sell surplus SO_2 emission allowances that resulted from this reduction. While the reduction at Coal Creek is not necessarily permanent or enforceable, the facility has indicated that it intends to continue to operate at year 2000 emission levels. EPA agreed to model the source's current year emissions using only 2000 data with the understanding that the source would need to make those reductions permanent and enforceable if, in fact, they are needed to show compliance with the SO_2 Class I increments.

Montana-Dakota Utilities Co.'s Heskett Station (Unit 1) emissions are also only based on year 2000 CEMS data. Unit 1, at 25 MW, is not required to report to the EPA Acid Rain Database. Since hourly CEMS data were only available for the year 2000 from the State we did not include 1999 emissions in our calculations. Unit 1 is a relatively small part of the inventory so we did not pursue obtaining 1999 CEMS data for the Unit.

PPL Corporation's Colstrip power plant in Montana has 4 units. Units 1 and 2 were both constructed before the major source baseline date for SO_2 (January 6, 1975). We did not obtain baseline emission information for these units but know, from reviewing the available data in the EPA Acid Rain Database, that emission trends from 1980 to today are relatively flat or even slightly down. This suggests that increment consuming emissions would be low and so we did not include these units in the inventories. Units 3 and 4 were both constructed after the major source baseline date for SO_2; emissions for both units were obtained from the EPA Acid Rain Database and are based on 1999 and 2000 CEMS data divided by 365 days to estimate 24 hour emissions. A more refined analysis could be made of Units' 3 and 4 increment consuming emissions, to be consistent with the methodology used for major North Dakota sources, however such an analysis did not seem warranted given the units' geographic location and, consequently, their negligible contribution to increment concentrations in any of the Class I areas modeled.

Current year emissions for the power plants are summarized in Table 3-1.

Table 3-1
CURRENT YEAR SO_2 EMISSIONS FOR POWER PLANTS
Based on CEMS data from EPA's Acid Rain Database

Source	1999 Actual Emissions			2000 Actual Emissions			**Current Year Emissions**	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	**2yr-90% 24 hour [lb/hr]**	**2-yr avg annual [TPY]**
Basin Electric Power Cooperative - Antelope Valley Station								
Units 1 + 2	4,350	3,620	15,516	4,940	3,291	13,047	**3,598**	**14,282**
Otter Tail - Coyote Station								
Unit 1	5,799	5,126	20,040	5,115	4,655	14,521	**5,077**	**17,281**
Great River Energy - Coal Creek								
Unit 1[1]	7,744	7,194	23,551	5,287	4,195	14,332	**4,195**	**14,332**
Unit 2[1]	7,175	6,891	26,192	4,608	3,552	12,817	**3,552**	**12,817**
PPL Corp. - Colstrip (Montana)								
Unit 3[2]	n/a	n/a	3,030	n/a	n/a	2,859	**672**	**2,945**
Unit 4[2]	n/a	n/a	3,293	n/a	n/a	2,315	**640**	**2,804**
Minnkota Power Cooperative - Milton R. Young Station								
Unit 1	7,088	5,575	19,481	7,082	5,599	18,095	**5,575**	**18,788**
Unit 2	7,535	6,161	21,863	6,838	6,089	21,134	**6,128**	**21,499**
Basin Electric Power Cooperative - Leland Olds Station								
Unit 1	5,956	4,891	16,802	5,970	4,965	16,864	**4,931**	**16,833**
Unit 2	11,623	10,282	33,306	11,796	9,877	28,587	**10,179**	**30,947**
Montana-Dakota Utilities Co. - Heskett Station								
Unit 1	1999 CEMS data not available			537	348	1,022	**348**	**1,022**
Unit 2	1,227	833	2,208	1,080	822	1,778	**831**	**1,993**
Great River Energy - Stanton Station								
Unit 1	3,078	2,371	8,241	3,047	2,523	7,017	**2,456**	**7,629**
Unit 10	357	327	1,241	402	307	972	**320**	**1,107**

Source	1999 Actual Emissions			2000 Actual Emissions			**Current Year Emissions**	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	**2yr-90% 24 hour [lb/hr]**	**2-yr avg annual [TPY]**
TOTAL	**63,931**	**53,271**	**194,764**	**56,702**	**46,223**	**155,360**	**48,502**	**164,277**

[1] Current year emissions are based on year 2000 CEMS data only. See discussion above.

[2] 24-hour current year emissions are based on annual CEMS data divided by 365 days. See discussion above.

No CEMS data or recent emissions data were readily available for the two gas processing plants (Grasslands Gas and Little Knife Gas Plant) and the coal gasification plant (Greatplains Synfuels Plant), so EPA used the same emissions estimates that NDDH used in their 1999 draft study. Modeled short-term emission rates for these plants are as follows:

Grasslands Gas Plant:	273 lb/hr
Little Knife Gas Plant:	427 lb/hr
Dakota Gasification - Greatplains Synfuels Plant:	3323 lb/hr

3.2 Base Year Inventory

As in the current year inventory, emissions for the base year inventory are generally based on actual emissions reflected by normal source operation for a period of 2 years. The two-year study period should generally be the two years preceding the minor source baseline date, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the baseline date (see 45 FR 52718, August 7, 1980). EPA rules and guidance allow the potential to emit to be used if little or no operating data are available, as in the case of a permitted emission unit constructed before the major source baseline date but not yet in operation at the time of the minor source baseline date (see 40 CFR 51.166(b)(13), p. C.11 of the NSR workshop manual[6], and 45 FR 52718, col. 3, August 7, 1980).

Four of the seven coal-burning power plants in North Dakota commenced construction before the major source baseline date for SO_2 (January 6, 1975). These include Minnkota Power Cooperative's Milton R. Young Station (Units 1 and 2), Basin Electric Power Cooperative's LeLand Olds Station (Units 1 and 2), Montana-Dakota Utilities Company's Heskett Station (Units 1 and 2) and Great River Energy's Stanton Station (Unit 1). These units are all included in the major source base year emission inventory. No major sources in this analysis that were built before the major source baseline date reported any physical change or change in the method of operation after the major source baseline date but before the minor source baseline dates (*i.e.*, all emissions prior to the applicable minor source baseline dates are considered to be baseline emissions).

Following is a brief description of each baseline source, based on information from EPA's Acid Rain Database (see http://www.epa.gov/airmarkets/picturethis/index.htm):

Minnkota Power Cooperative - Milton R. Young Station
Unit 1 - 257 MW, lignite-fired cyclone boiler, uncontrolled for SO_2
Unit 2 - 477 MW, lignite-fired cyclone boiler, SO_2 control - (dry alkali) flue gas desulfurization

Basin Electric Power Cooperative - Leland Olds Station
Unit 1 - 216 MW, lignite-fired dry bottom boiler, uncontrolled for SO_2
Unit 2 - 440 MW, lignite-fired cyclone boiler, uncontrolled for SO_2

Montana-Dakota Utilities Co. - Heskett Station
Unit 1 - 25 MW, lignite-fired, uncontrolled for SO_2
Unit 2 - 75 MW, lignite-fired boiler retrofitted to a fluidized bed combustor in 1987, uncontrolled for SO_2

Great River Energy - Stanton Station
Unit 1 - 187 MW, lignite-fired dry bottom boiler, uncontrolled for SO_2

3.2.1 Base Year Inventory for North Dakota Class I Areas

In general, the base year inventory for the North Dakota Class I areas is based on actual emissions averaged over the two-year period 1976-1977. For all baseline emissions we used AP-42 emission factors for uncontrolled lignite-fired boilers (see AP-42[8], section 1.7, Table 1.7-1).

The only data available to us for these baseline sources for the years 1976 and 1977 are what is reported to the State in the Annual Emission Inventory Reports (*e.g.*, coal use, sulfur content, coal feed rates, etc.). Based on this information, several options existed for determining the short term maximum actual emission rates needed for the modeling analysis.

One option for determining short-term emissions is to calculate an emission rate based on an AP-42 emission factor (in units of lb_{SO2}/ton_{coal}) and the maximum sulfur content (wt. %) and maximum coal feed rate (ton_{coal}/hr) supplied in the Annual Emission Inventory Reports. However, we believe that the maximum coal feed rate numbers are very uncertain. We are not aware of any official method or quality assurance process that has been used to arrive at these numbers. According to the State, at least one company has questioned the accuracy of these data. For these reasons, we dismissed this option for calculating short-term emissions. In using maximum hourly feed rates and maximum sulfur content, this option would likely overpredict SO_2 emissions in the base year.

[8] Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, January 1995, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, http://www.epa.gov/ttn/chief/ap42/index.html.

A second option for determining short-term emissions is to calculate annual emissions (based on an AP-42 emission factor (in lb_{SO_2}/ton_{coal}), average sulfur content (in wt. %) and annual coal usage (in ton_{coal}/yr)) and divide this number by 365 days per year to arrive at a lb per day emission rate. Since this method is based on *average* annual operation data, this option would likely underpredict SO_2 emissions in the base year. For this reason we also dismissed this option, except as a screening approach for sources with very low emission rates, or at great distances from the Class I areas.

A third option for determining short-term emissions is to calculate annual emissions (again, based on an AP-42 emission factor (in lb_{SO_2}/ton_{coal}), average sulfur content (in wt. %) and annual coal usage (in ton_{coal}/yr)) and then apply the peak-to-mean ratio from the current year CEMS emissions to the mean annual base year emissions to get peak base year emissions. Specifically, the ratio of the annual average emission rate from the 1999-2000 CEMS data to the 90^{th} percentile 24-hr emission rate (from 1999-2000 CEMS data) is applied to the annual average emission rate in the base year to calculate the 24-hr emission rate in the base year. Since short-term emission rates in the current year inventory are based on the 90^{th} percentile of the 24-hour average (see Section 3.1), this option would give the best estimate of the 90^{th} percentile 24-hr emission rate in the base year and would, therefore, be consistent with the short-term emissions used in the current year inventory. For this reason we chose this option for calculating short-term SO_2 emissions in the base year.

EPA believes any increment analysis should follow the same methodology for determining emissions in the base year as in the current year, particularly where like data are available, as is the case here. Using the same methodology allows an objective comparison (and use) of the two data sets. To do otherwise does not provide "comparable" data sets. If different methodologies were used to determine emissions for the base year and the current year, comparing the two data sets would produce inappropriate conclusions since the data sets had been derived using different methodologies.

Annual average emissions (for use in option 3 above) are based on an AP-42 emission factor for uncontrolled lignite-fired boilers of 30 S (see AP-42, section 1.7, Table 1.7-1). Annual Emission Inventory Reports for each baseline source were obtained from the State of North Dakota for 1976 and 1977. From these reports, annual coal usage and average sulfur content data were used to calculate annual average SO_2 emissions. For example, annual average base year SO_2 emissions for Minnkota's Milton R Young Unit 1 are:

$$SO_2\ emissions_{1976}\,[TPY] = 30 * (0.52\%)\frac{lb_{SO2}}{ton_{coal}} * 1{,}581{,}000\frac{ton_{coal}}{yr} * \frac{1\,ton_{SO2}}{2000\,lb_{SO2}} = 12{,}332\frac{ton_{SO2}}{yr}$$

$$SO_2\ emissions_{1977}\,[TPY] = 30 * (0.63\%)\frac{lb_{SO2}}{ton_{coal}} * 1{,}527{,}511\frac{ton_{coal}}{yr} \bullet \frac{1\,ton_{SO2}}{2000\,lb_{SO2}} = 14{,}435\frac{ton_{SO2}}{yr}$$

$$2yr\ average\ SO_2\ emissions\,[TPY] = \frac{(12{,}332 + 14{,}435)}{2} = \underline{\underline{13{,}383\ TPY}}$$

Short-term emissions are then calculated based on the peak-to-mean ratio from current year emissions. For example, short-term SO_2 base year emissions for Minnkota's Milton R Young Unit 1 boiler are:

$$peak-to-mean\ ratio_{1999-2000} = \frac{18{,}788\frac{ton}{yr}(2yr\ annual\ avg_{1999-2000})}{5575\frac{lb}{hr}(90^{th}\%\ 24hr\ avg_{1999-2000}) * \frac{8760\,hr}{yr} * \frac{ton}{2000\,lb}} = 1.30$$

$$base year SO_2\ emissions[\frac{lb}{hr}] = 13{,}383\frac{ton}{yr} * 1.30 * \frac{yr}{8760hr} * \frac{2000lb}{ton} = \underline{\underline{3972\frac{lb}{hr}}}$$

For the most part we used the above method for calculating base year emissions. However there are a few exceptions. Minnkota's Milton R Young Unit 2 had only been in operation for 9 months as of the minor source baseline date and those 9 months do not appear to be representative of normal operating conditions. The unit was apparently out of compliance with its allowable emissions for many months after the unit began operation. Considering that we do not have two years of actual emissions at the time of the minor source baseline date for this unit, as well as the fact that the unit really did not begin "normal operations" until after the baseline date was triggered, we believe it is appropriate in this situation to consider the allowable emissions of Minnkota's Unit 2 as its emissions at the time of the baseline date (see 45 FR 52718, col. 3, August 7, 1980). Furthermore, since any emissions increases above a source's allowable emission rate at the time of the minor source baseline date must be considered as increment consuming emissions, it would not be appropriate to use Unit 2's actual emission rate at the time of the minor source baseline date as the baseline emission rate. Therefore, we modeled a short-term emission rate of 5635 lb/hr (the allowable emission rate) for this unit.

The other exception in calculating baseline emissions is for Montana-Dakota Utilities Co.'s Heskett Unit 1 emissions. Since Heskett Unit 1 is not an acid rain source, no CEMS emissions are reported to the Acid Rain Database. Hourly CEMS data were only available for the year 2000 from the State of North Dakota. Therefore, the peak-to-mean ratio used to calculate short-term emissions in the base year is only based on year 2000 data (as opposed to both 1999 and 2000 data, used for all other baseline sources).

Baseline emissions for the Class I areas in North Dakota are summarized in Table 3-2.

Table 3-2
SO_2 BASELINE EMISSIONS FOR **NORTH DAKOTA** CLASS I AREAS
Based on AP-42 and annual emission inventory reports provided by ND for 1976-1977
SO_2 minor source baseline date = December 17, 1977

Source	Emission Factor	1976 Actual Emissions			1977 Actual Emissions			**Baseline Emissions**	
	$[lb_{SO2}/ton_{coal}]$	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	**annual [TPY]**	**24-hr[1] [lb/hr]**
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.52	1,581,000	12,332	0.63	1,527,511	14,435	**13,383**	**3,972**
Unit 2[2]	n/a	n/a	n/a	24,682	n/a	n/a	24,682	**24,682**	**5,635**
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.45	1,255,995	8,478	0.44	1,306,785	8,625	**8,551**	**2,499**
Unit 2	30(S)	0.45	1,958,680	13,221	0.44	1,964,660	12,967	**13,094**	**4,305**
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.75	159,196	1,791	0.68	171,162	1,746	**1,768**	**602**
Unit 2	30(S)	0.75	376,017	4,230	0.68	406,145	4,143	**4,186**	**1,749**
Great River Energy - Stanton Station									
Unit 1	30(S)	0.65	746,205	7,275	0.64	737,106	7,076	**7,176**	**2,310**
TOTAL								**72,841**	**21,072**

[1] Based on the ratio of annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

[2] Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col. 3, August 7, 1980.

3.2.2 Base Year Inventory for Montana Class I Areas

In general, the base year inventory for the Montana Class I areas was compiled using the same method as for the North Dakota Class I inventory. The only difference is the use of 1977 and 1978 emission inventory data for calculating the annual average emission rates. While we still used allowable emissions for Minnkota's Milton R Young Unit 2 in 1977, we were able to calculate actual emissions for 1978. Since Unit 2 commenced construction after August 17, 1971, it was permitted according to the New Source Performance Standards (NSPS) in 40 CFR

Part 60 Subpart D. Therefore, we calculated actual emissions for the unit based on this 1.2 lb_{so2}/mmBtu standard, the average heat content of the coal in 1978 and the annual coal usage rate for that year. We then applied the peak-to-mean ratio from 1999-2000 CEMS data to calculate a short-term emission rate and averaged that with the 1977 allowable emission rate of 5635 lb/hr to arrive at a short-term emission rate for the unit for the base year. Other possibilities we considered for determining baseline emissions for this unit were: (1) to just use the 1978 actual numbers (not averaged with the allowable emissions for 1977); and (2) to use the allowable emission rate for both 1977 and 1978 emissions. EPA solicits comments from the public on how to determine the most representative baseline emission rate for this source.

Baseline emissions for the Class I areas in Montana are summarized in Table 3-3.

Table 3-3
SO_2 BASELINE EMISSIONS FOR **MONTANA** CLASS I AREAS
Based on AP-42 and annual emission inventory reports provided by ND for 1977-1978
SO_2 minor source baseline date = March 26, 1979

Source	Emission Factor [lb_{SO2}/ton_{coal}]	1977 Actual Emissions			1978 Actual Emissions			**Baseline Emissions**	
		avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	**annual [TPY]**	**24-hr[1] [lb/hr]**
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.63	1,527,511	14,435	0.65	1,427,485	13,918	**14,176**	**4,208**
Unit 2[2]	1.2 lb/mmBtu	n/a	n/a	24,682	0.65	1,956,191	15,087	**19,884**	**4,970**
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.44	1,306,785	8,625	0.74	1,361,539	15,113	**11,869**	**3,469**
Unit 2	30(S)	0.44	1,964,660	12,967	0.74	2,435,160	27,030	**19,999**	**6,575**
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.68	171,162	1,746	0.71	161,755	1,723	**1,734**	**590**
Unit 2	30(S)	0.68	406,145	4,143	0.71	342,560	3,648	**3,895**	**1,628**
Great River Energy - Stanton Station									
Unit 1	30(S)	0.64	737,106	7,076	0.61	577,004	5,280	**6,178**	**1,989**
TOTAL								**77,736**	**23,428**

[1] Based on the ratio of annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

[2] Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718. col. 3, August 7, 1980. 1978 emissions are based on an emission limit of 1.2 lb_{SO_2}/mmBtu for NSPS boilers (see 40 CFR Part 60 Subpart D) and an average heat content of 6427 Btu/lb_{coal}.

3.3 Increment Consuming Emissions

Tables 3-4 and 3-5 summarize the increment consuming emissions from the inventories in Section 3.1 (Current Year Emissions) and 3.2 (Base Year Emissions).

Table 3-4

SO_2 INCREMENT CONSUMING EMISSIONS FOR **NORTH DAKOTA** CLASS I AREAS

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station						
Units 1+2	n/a	n/a	3,598	14,282	3,598	14,282
Otter Tail - Coyote Station						
Unit 1	n/a	n/a	5,077	17,281	5,077	17,381
Great River Energy - Coal Creek Station						
Unit 1[4]	n/a	n/a	4,195	14,332	4,195	14,332
Unit 2[4]	n/a	n/a	3,552	12,817	3,552	12,817
PPL Corp. - Colstrip (Montana)						
Unit 3	n/a	n/a	672	2,945	672	2,945
Unit 4	n/a	n/a	640	2,804	640	2,804
Minnkota Power Cooperative - Milton R.Young Station						
Unit 1	3,972	13,383	5,575	18,788	1,603	5,405
Unit 2[5]	5,635	24,682	6,128	21,499	493	(3,184)
Basin Electric Power Cooperative - Leland Olds Station						
Unit 1	2,499	8,551	4,931	16,833	2,432	8,282
Unit 2	4,305	13,094	10,179	30,947	5,874	17,853

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Montana Dakota Utilities Co. - Heskett Station						
Unit 1[6]	602	1,768	348	1,022	(254)	(746)
Unit 2	1,749	4,186	831	1,993	(918)	(2,193)
Great River Energy - Stanton Station						
Unit 1	2,310	7,176	2,456	7,629	146	453
Unit 10	n/a	n/a	320	1,107	320	1,107
Gas Processing Plants						
Grasslands	n/a	n/a	273	n/a	273	n/a
Little Knife	n/a	n/a	427	n/a	427	n/a
Dakota Gasification Plant						
Greatplain Synfuels	n/a	n/a	3,323	n/a	3,323	n/a
TOTAL	**21,072**	**72,840**	**52,525**	**164,277**	**31,453**	**91,538**

[1] Negative numbers indicate increment expanding emissions (*i.e.*, current year emissions are lower than base year emissions).

[2] Annual numbers are based on the Annual Emission Inventory Reports from 1976-1977 (e.g., *avg* S, annual coal use) and AP-42 emission factors. 24-hr numbers are based on the ratio of the annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

[3] Based on the 90th percentile of the 24-hr average from 1999 and 2000 CEMS data.

[4] Based on 2000 CEMS data only.

[5] Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col 3, August 7, 1980.

[6] Current year emissions based on 2000 CEMS data only. Unit 1 does not report to the Acid Rain Database; hourly CEMS data were only available for 2000 from the State.